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A STUDY OF THE CORE OF THE YANAWAY WELL NO. 33 IN
THE SIGGINS POOL

By J. E. Lamar

INTRODUCTION

As the amount of oil in Illinois which can be produced economically by pumping decreases, the application of methods for increasing recovery becomes necessary in order to avert a premature abandonment of many pools and consequent loss of a large amount of recoverable oil. However, the intelligent application of improved recovery methods requires specific information concerning the oil sands, their detailed character, and their vertical and horizontal extent. Unfortunately such data are not generally obtainable from the available records, most of which are all too brief. Core drilling is therefore advisable in any attempt to determine if the amount of oil remaining in the sand is sufficient to warrant improved recovery methods and whether or not other conditions are right for the successful application of mining, flooding, or repressuring in any given pool. The purpose of this paper is to indicate the type of information which may be obtained from a single core and to show its bearing on deductions concerning some of the items mentioned above. The Petroleum Engineering Section of the Illinois State Geological Survey is prepared to make similar studies in other fields of the State, wherever satisfactory core samples are available.

LOCATION

The Yanaway well No. 33 is located in the SW. $\frac{1}{4}$ SE. $\frac{1}{4}$ sec. 1, T. 10 N., R. 10 E., in the north part of the Siggins pool in northeastern Cumberland County. This pool appears to be one of the most promising in the State for the application of mining methods of oil recovery. For this reason detailed information on sand conditions and character should be

valuable in deciding how mining can be best applied. Though the Yanaway No. 33 is technically an edge well, the data from it are thought to be not unlike those of the rest of the pool in the major features.

METHOD OF CORING AND SAMPLING.

The core of the sand of the Yanaway well was obtained with a core bit for cable tools furnished by the Keystone Driller Company of Joplin, Missouri. The Ohio Oil Company arranged with the Illinois Geological Survey for collecting and studying samples of core from practically every foot of the sand.

The samples of core thought to be oil sand were removed from the core barrel, rinsed rapidly in water to remove the mud usually coating them, wrapped in wax paper and sealed by immersing in melted paraffin. Other samples were similarly wrapped but not in all instances immediately after being taken from the core barrel. Laboratory studies of the core were made along the four following lines: (1) description of core samples, (2) oil content, (3) porosity, and (4) texture. This work was largely done by C. R. Clark.

STUDIES OF THE CORE

DESCRIPTION OF SAMPLES

The samples of core were examined under the microscope and identified as to kind and character of rock. The log of the sand is given below and is shown graphically in figure 1.

Log of Yanaway well No. 33, Ohio Oil Company

	Thickness <i>Feet</i>	From <i>Feet</i>	To <i>Feet</i>
Shale, plastic, light gray-green.....			400½
Sandstone, gray, clayey, interbedded with gray siltstone and some shale; basal 3 feet limy.....	13½	400½	414
Sandstone, medium-grained, buff-gray..	14	414	428
Shale, gray, bluish-gray and brown, carbonaceous, broken by siltstone; splits into thin flakes.....	44	428	472
Coal	1	472	473
Shale, gray or greenish-gray; soft at top, hard at bottom; mostly sandy...	17	473	490
Sandstone, light gray, fine- to medium- grained	10	490	500
Shale, dark gray, splits into thin flakes; moderately hard.....	4	500	504
Coal	1	504	505
Shale, plastic, gray, moderately hard..	1	505	506
Coal	2	506	508



Shale and siltstone interbedded, gray, bluish-gray and greenish-gray; soft in upper part; hard, sandy, locally limy in basal 18 feet.....	41	508	549
Coal	2	549	551
Shale, gray, greenish-gray and bluish-gray, locally sandy or limy; basal portion contains plant fossils.....	15	551	566
Coal	8	566	574
Shale, gray, hard, sandy to very sandy; contains plant fossils.....	7	574	581
Sandstone, gray, dense, hard.....	5	581	586
Shale and siltstone interbedded, gray or bluish-gray; locally sandy, coaly or limy	8	586	594
Siltstone, bluish-gray, hard, clayey; splits into thin flakes.....	13	594	607
Shale, bluish-gray, gritty.....	3	607	610
Siltstone, light gray, clayey, middle foot limy	3	610	613
Shale, bluish-gray, hard.....	5	613	618

The term siltstone used in the above log is used to describe those sediments composed dominantly of fine gritty particles, too fine to be called sand and too coarse to be called shale. Inasmuch as siltstones ordinarily contain a high percentage of clay their effect on oil accumulation and migration is similar to that of shale.

OIL CONTENT OR PER CENT OF SATURATION

The oil content was determined as the difference in weight of a sample before and after the oil had been removed by means of a Soxhlet extractor—an apparatus especially designed for removing oils from solids. The graphs of per cent saturation given in figure 1 are thought to be misleading for three reasons. (1) Despite the fact that the core barrel of the bit was supposed to have been on bottom at all times, the way in which the core was broken in the barrel suggested that it had been raised from the bottom of the hole frequently during drilling. This would permit the escape of oil from the core. (2) the rate of drilling with the core bit was comparatively slow and there was therefore time for a considerable proportion of the oil included in the core to have escaped. Some biscuits of core bubbled gas and oil after removal from the core barrel and there is no reason to suppose this had not also been happening while the core was in the core barrel. (3) Some of the core was in complete or partial contact with the mixture of oil and water in the hole, which afforded opportunity for oil to penetrate cracks or fractures in the core. The oil content of some of the shale samples is thought to be of this nature.

POROSITY

The porosity was determined by extracting the oil from the sample of core and then measuring the volume of fluid which it displaced when saturated. This gave the volume of the sample with the pores filled. The sample was then crushed and the volume of the resulting grains measured by determining the amount of fluid they displaced. The porosity was calculated as follows:

$$\text{Per cent porosity} = \frac{(\text{Vol. original sample}) - (\text{Vol. sand grains}) \times 100}{(\text{Vol. original sample})}$$

TEXTURE

The texture of a number of selected samples was determined by making sieve analyses of them. The clay recorded in figure 1 is the material which had not settled through 15 inches of water in 10 minutes. The other grade sizes were determined on Tyler Standard Screen Scale sieves.

INTERPRETATION OF RESULTS OF TESTS

GENERAL SAND CONDITIONS

SIGNIFICANCE OF SILTSTONES

One of the important facts brought out by the study of the Yanaway core is the existence of siltstone as distinct individual beds and as "breaks" within the major sand-bodies. By reason of their intermediate character between sandstone and shale, siltstones frequently grade laterally, in comparatively short distances, into either sandstone or shale. It is possible therefore that the siltstones of the Yanaway No. 33 may be sandstone or shale in other wells of the Siggins pool. It is thought that this phenomenon probably accounts for the variation in the thickness of the producing sands in different parts of the field and may also indicate why as many as six oil sands are reported in some wells.

OIL-SAND HORIZONS

The log given in figure 1 and on preceding pages suggests that in the northern part of the Siggins pool there are five horizons where sands may be expected to occur, as follows: (1) the upper sand found from 400½ to 428 feet; (2) the siltstone horizon from 447 to 450 feet; (3) the middle sand from 490 to 500 feet; (4) the siltstone zone from 515 to 531 feet; and (5) the lower sand and siltstone zone from 581 to 613 feet. Of these the second is thought to be of the least importance as a possible sand horizon. The frequent changes in the character of the formations in the lower 118 feet of the well indicate unstable conditions of deposition in the sea in which these sediments were laid down, and consequently lateral variations in the sandstones and siltstones of the lower 118 feet of the Siggins sand will probably be found to be greater and more abrupt than in the upper 100 feet.

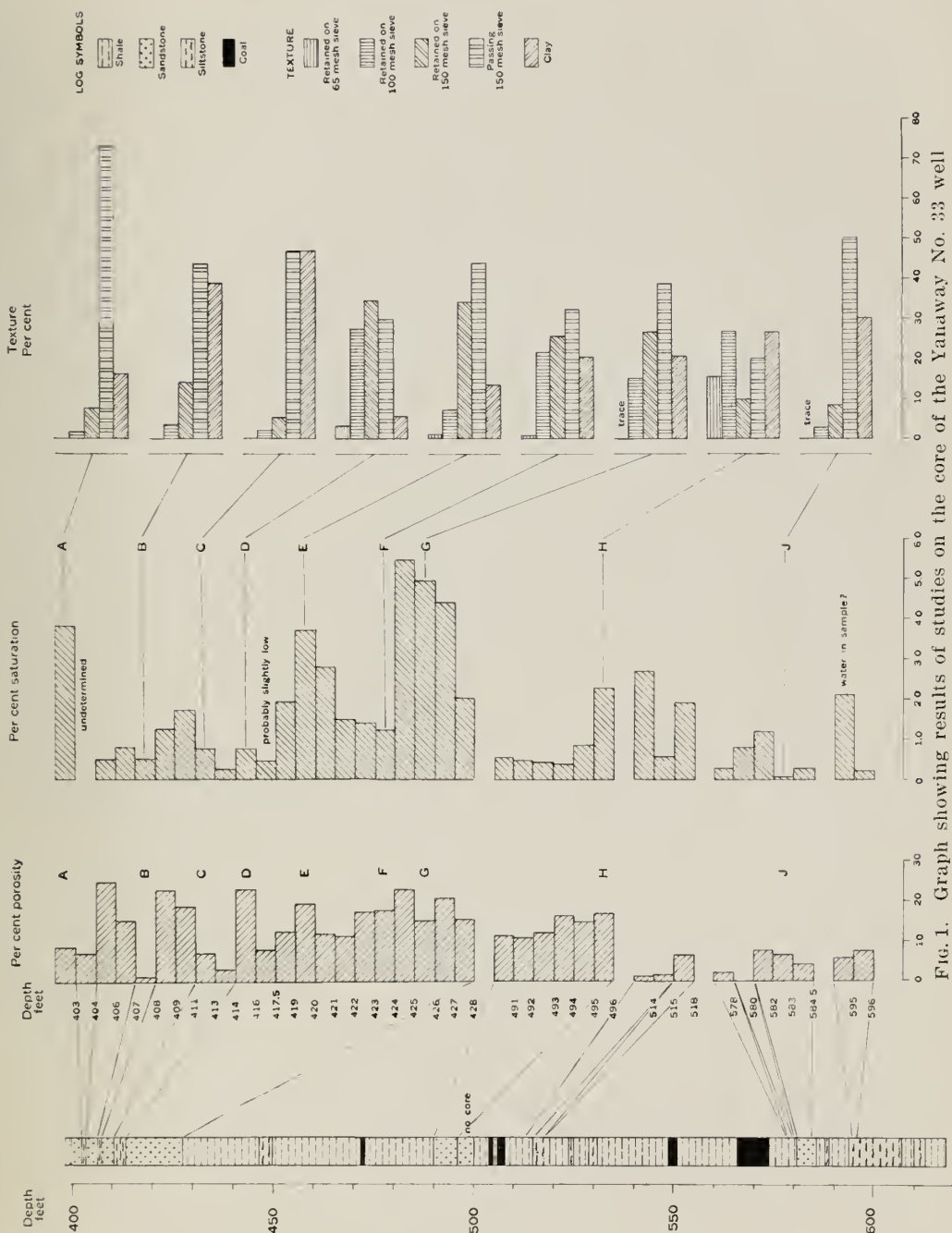


FIG. 1. Graph showing results of studies on the core of the Yanaway No. 33 well

THICKNESS OF OIL SANDS

If the thickness of the sandstones found in the core of the Yanaway No. 33 be used as criteria, the sand records available for many of the wells in the Siggins pool are misleading in that they show far too great a thickness of sand. It is obvious that not all the formations logged as sand were productive of oil, but the records fail to indicate how thick the sand bodies are and at what depth they were found. Sand records at hand show from 18 to 91 feet of upper sand, but it is doubtful if the 91-foot thickness recorded was actually all sand. More probably, the sediments logged as sand were the upper sandstone and a series of interbedded shales and sandstones lying below. In the case of the 18-foot sandstone it would appear that some of the upper part of the upper sand of the Yanaway No. 33 grades laterally into shale.

SEDIMENTARY STRUCTURES IN THE SANDSTONES AND SILTSTONES

Judging by the manner in which the core broke, the three sands are all thin-bedded, in layers from $\frac{1}{4}$ inch to 2 inches thick. The bedding planes are irregular and many of them have thin films of highly micaceous clay coating them. Several pieces of core were cross-bedded. The siltstones are even more irregularly bedded than the sandstones and are usually very thin-bedded, resembling shale.

THE UPPER SAND

INTRODUCTION

Since the upper sandstone is the most important in the Siggins pool and is the sand on which improved recovery methods would most logically be applied, it is discussed in detail. The general lithologic characteristics exhibited by the upper sandstone are also present in the two lower sands.

OCCURRENCE OF OIL

Examination of the core of the upper sand as it came from the core barrel showed that the oil in it was not uniformly distributed. This is further borne out by the per cent saturation of the core samples (fig. 1) which show, considering only the outstanding features, an irregular arrangement of the points of high and low saturation, although in general the lower portion is shown to have a higher saturation than the upper.

Some pieces of core showed even more restricted localization of the oil than indicated above, for in many of them by far the greatest amount of oil was found in a thin streak of coarse and apparently very porous sandstone which varied from $\frac{1}{8}$ to $\frac{1}{4}$ of an inch in thickness. The cementation of this coarse sandstone was much less firm than that elsewhere, inasmuch as the core commonly broke along the coarser bands.

TEXTURE OF THE SAND

The texture of parts of the three sandstones in the Yanaway No. 33 well are shown graphically in figure 1. In general it may be said that all the sandstones are fine-grained and that all have a high clay content, excepting sample D. The clay is present as a filling between the sand grains. Sample A is high in very fine sand as might be expected from its position immediately below a shale. The siltstone "breaks" of the upper sand are shown in graphs B and C, with their high per cent of clay and material passing a 150-mesh screen. Graphs D, E, F, and G indicate the texture of the main body of the upper sand.

The middle sand, illustrated by Graph H, is the coarsest of any of the sands tested. The lower sand is very fine-grained, high in clay and material passing a 150-mesh sieve, and approaches a siltstone in composition as shown by Graph J.

POROSITY

DISTRIBUTION

The results of the porosity determinations on samples of the sandstones and siltstones are shown in figure 1. The porosity determinations as a rule serve to distinguish between the siltstones and sandstones, the former being much less porous than the latter. The upper sand shows considerable variation in porosity, doubtless due to variations in the texture of the sandstone. The middle and lower sands have comparatively uniform porosities.

RELATION OF CLAY CONTENT TO POROSITY

It has been previously suggested that the clay present in the sands of the Yanaway No. 33 well fills the spaces between the sand grains and thereby reduces the porosity of the sandstones. This statement is borne out by data shown in figure 1. Graphs of texture show a high clay content for samples B and C. The porosity is low. Samples D, E, and F show decreasing porosity and increasing clay content. Sample H is, in a way, an exception. Both its clay content and porosity are comparatively high, but this is because it has so much medium-grained sand that the pores are larger and the amount of fine material present is insufficient to fill the pores as completely as it does in the other samples.

RECOVERABLE OIL

Inasmuch as the Yanaway No. 33 is an edge well, the saturation of the sands is doubtless lower than that of the sand in the more productive portion of the Siggins pool. However, assuming an average saturation of only 3 per cent, which is probably a conservative estimate of the actual saturation of the upper sandstone in the Yanaway No. 33, and a 60 per cent recovery of the oil remaining, the production would still be over 2,100 barrels per acre for the upper sand. This figure is essentially an estimate.

yet it is significant of the larger recovery which may be anticipated for other parts of the pool.

SUMMARY AND BEARING OF STUDIES ON IMPROVED RECOVERY METHODS

The study of the core of Yanaway No. 33 alone, does not yield definite data on the advisability of mining, flooding, or repressuring in the Siggins pool, but it nevertheless indicates certain factors which must be considered before improved methods are applied. These factors are as follows:

(1) Three sands which contain oil are present in the northern part of the pool in which the Yanaway No. 33 is located.

(2) Two siltstone horizons are present; these may be sandstone elsewhere in the Siggins pool.

(3) The sands of the Siggins pool are probably lenticular and therefore a thorough study of sand records, supplemented by core drilling, should be made to outline in detail the major sand bodies.

(4) Of the three sands present the upper is the thickest and probably contains the most oil. It is therefore the most logical sand body for the application of improved recovery methods.

(5) The upper sandstone is fine-grained and lies in thin, irregular beds. There are shale and siltstone "breaks," particularly in the upper part of the sandstone.

(6) The porosity of the sandstone portions of the upper sand varies from 8 to 23 per cent.

(7) The average saturation of the sandstone beds of the upper sand is 2.2 per cent. This is thought to be too low because of a probable loss of oil from the core samples.

(8) Assuming 60 per cent recovery of the oil now in the upper sand and 3 per cent saturation, there are about 2100 barrels of recoverable oil per acre.

CORROSION IN THE EASTERN ILLINOIS OIL FIELDS

By J. E. Lamar and C. R. Clark

INTRODUCTION

The general problem of corrosion is of such great industrial importance that the reports on various phases of the subject comprise a voluminous literature.¹ Corrosion of the metallic equipment used in the business of producing oil and gas is a special phase of the corrosion problem, which, because of its economic importance to the petroleum industry, has been the subject of special studies.² The work thus far reported has been either of a general nature or else has had particular application to problems other than those confronting the Illinois oil operators. Therefore, the Petroleum Engineering section of the Illinois Geological Survey undertook a series of field investigations in the eastern Illinois oil fields in order to determine the causes of oil-field corrosion more precisely, so that any remedies available might be applied. The purpose of this report is to make the results of the investigation available to oil operators.

General, systematic studies of the waters in the Illinois oil fields were begun by the Illinois Geological Survey in 1924. One of the problems considered in this investigation was the possibility of determining the relative corrosiveness of oil-field waters by comparing analyses of the mineral matter dissolved in them. Although these investigations are not yet completed, it has been concluded that the relative corrosiveness of waters cannot be determined on the basis of a chemical analysis.³

The new work undertaken by the Petroleum Engineering section consisted principally of a more extensive determination of two of the chemical properties of the oil-field waters: (1) the relative acidity, and (2) the hydrogen sulfide content. Quantitative determination of these properties was undertaken in the eastern Illinois oil fields during the summer of 1927, and an attempt was made to correlate the results of these tests with the relative corrosiveness of the waters.

One of the outstanding difficulties in the study of oil-field corrosion problems was the absence of any comparable data by which the rate of corrosion could be determined. Comparison of corrosion in wells in individual pools or districts was fairly satisfactory, for the judgment of field superintendents who were familiar with operating conditions over such areas could be relied upon to classify the waters in a general way. No quantitative determinations of the rate of corrosion could be made, however, so the terms "corrosive", "slightly corrosive" and the like, as used in this

¹ For a comprehensive bibliography on the general subject of corrosion, see Speller, F. N., *Corrosion*, pp. 565-577, McGraw-Hill Book Co., New York, 1925.

² Mills, R. Van A., *Protection of oil field equipment from corrosion*, U. S. Bureau of Mines Bull. 233, 1925.

³ Moulton, Gail F., Illinois State Geol. Survey, personal communication.

report, are definitely significant only of the relative corrosiveness in the specific field under discussion. In comparing fields as units, the statements regarding corrosiveness are the concensus of opinion of a large number of oil men.

ACKNOWLEDGMENTS

The writers wish to express their appreciation to the many members of the petroleum industry of Illinois for their assistance and advice in matters pertaining to this investigation, and to the State Water Survey for their valuable cooperation in making the chemical analyses of the samples of oil-field waters. Gail F. Moulton's constructive criticism of the manuscript has also been valuable.

CONCLUSIONS AND SUGGESTIONS

From the subsequent detailed description of corrosion in the southeastern Illinois oil fields it is evident that the oil-field brines are responsible for the corrosion of the oil field equipment. Although no chemical characteristics of the brines are clearly responsible for their corrosive action, in the majority of cases it appears that the action of hydrogen sulfide, both as a gas and in solution, is the most important single factor.

Remedies for corrosion might be found in the use of materials which would resist the action of the waters. On account of the large amount of equipment required for each well, the number of alloys and metallic coatings which might be used is restricted by the necessity of low cost, and it is probable that not many alloys or coatings remain untried. The solution of the problem would therefore seem to lie along some other line.

Corrosion caused by waters which may be shut out of the wells by use of casing is easily controlled. In such a well the use of fluid mud, cement, or oil, behind the casing to protect it from contact with water should extend the life of the casing beyond the life of production. In certain parts of Illinois oil field work of this type should be very profitable.

There is little doubt that the water produced with the oil and which causes so much of the corrosion can be reduced in many places and entirely eliminated in a few of them. The amount of water produced has been observed to bear such a close relation to the rate of corrosion that it seems apparent that even a reduction in the amount of water handled with the oil would retard the rate of corrosion. The mudding off of corrosive waters and cementing off of bottom waters in the Flat Rock pool, undertaken in 1918 by the State Geological Survey in cooperation with the operators, is a good example of the type of repair work which may be done to reduce corrosion over some parts of the eastern oil fields. The work in the Flat Rock pool, Crawford County, resulted in satisfactory repairs on ten wells.⁴ The net result was that an average increase of six barrels

⁴ Tough, Fred B., Williston, Samuel H., and Savage, T. E., Experiments in water control in the Flat Rock pool, Crawford County; Illinois State Geol. Survey Bull. 40, pp. 97-140, 1919.

per day per well was obtained at an average cost of \$361 per well. It is difficult to measure the additional benefit from reduction in the amount of salt water handled, and therefore reduced lifting costs, as well as slower rates of corrosion, but the increased yield of oil more than paid the cost of the work.

Systematic petroleum engineering studies of other parts of the Illinois oil fields to determine the feasibility of similar repair work are justified by the results obtained in the work of 1918. Areas in which corrosion is very serious are particularly promising of financial gain from this sort of repair work because of the saving to be expected from fewer replacements of pumping equipment.

In anticipation of undertaking cooperation in well repair work the Petroleum Engineering section of the Illinois Geological Survey has conducted experimental laboratory studies on the setting of cements under various conditions, and on the preparation of fluid muds which will stay in suspension for long periods of time. The results of these investigations will be published in later reports. Requests for cooperation in the solution of water, cementing, mudding, and other problems in the field of petroleum engineering will be cordially received.

The remainder of the paper is devoted to a detailed discussion of the types of corrosion, the relation of the chemical composition of oil-field brines to corrosion, the importance of hydrogen sulfide in corrosion, substances that accelerate corrosion, the effect of corrosion on different materials used in oil well equipment and details of corrosion in the various oil fields of eastern Illinois.

TYPES OF CORROSION

INTRODUCTION

There are two important types of corrosion which do serious damage to oil-field equipment: (1) soil corrosion, which affects equipment buried in the soil, and (2) corrosion by oil-field brines and associated gases. Still another type, atmospheric corrosion or rusting, is also present, but as it is much slower and is comparatively easy to control, it is not discussed here.

SOIL CORROSION

Soil corrosion has been ascribed to an "acid" condition of the soil, but it is doubtful if this is generally the cause. Only in swampy and peaty soils is acid present in sufficiently large amounts to markedly increase the ordinary rate of soil corrosion. Many soils give an acid reaction if tested with an ordinary indicator like litmus, because the basic color of the litmus is adsorbed by the colloidal matter in the soil. Thus many soils have been classified as true acid soils when in reality they possess only "apparent acidity."

Corrosion which affects buried equipment is the result of an electro-chemical reaction between the metallic equipment and soil water containing dissolved salts and gases. That water is essential is evidenced by the fact that equipment buried in soil containing little or no moisture is not subject to soil corrosion.

Soil corrosion may be minimized by the application of various protective paints or coatings, either asphaltic or galvanized. In order to be effective these coatings must be moisture-proof. Great care should be exercised, therefore, to prevent cracking or chipping of the coating during handling and installing, for the protective seal must remain intact over the whole piece or much of its effectiveness will be lost.

WATER AND GAS CORROSION

Corrosion by oil-field brines and gases may affect any of the subsurface or surface equipment with which they come in contact—casing, tubing, sucker rods, lead lines, vacuum lines, condensers, and the like, all are subject to corrosion in some places. Not only is metallic equipment eaten away but also locally there is deposited contemporaneously a scale, usually largely composed of iron salts and sulfur, which often fills lead lines and vacuum lines to such an extent that they must be replaced.

Generally the worst corrosion is caused by bottom- or edge-waters. Other corrosive waters penetrated in drilling can be shut off by strings of casing which may be mudded or cemented.

Water and gas corrosion are, like soil corrosion, electro-chemical in their action. The rate of corrosion is governed largely by three factors: (1) the chemical composition of the oil-field brine, (2) the presence or absence of products of corrosion that may accelerate or retard corrosion, and (3) the character of the materials from which the oil-field equipment is made. These matters are considered in the above order in this report.

RELATION OF CHEMICAL COMPOSITION OF OIL-FIELD BRINES TO CORROSION

CHOICE OF WELLS FOR INVESTIGATION

Because of the impossibility of securing comparable data on the rate of corrosion, the selection of corrosive and noncorrosive waters for study was of necessity confined to groups of contrasting samples from individual pools. Waters from two different areas were chosen for study, the Parker Township pool in Clark County and the Bridgeport pool in Lawrence County. These areas were favorable for sampling because in both pools there are wells producing from the same sands and in close proximity to each other, some of which yield corrosive water and others noncorrosive water. The wells selected were known to be producing regularly and to be in good condition. By sampling in this way it was believed that the analyses of the corrosive and noncorrosive waters in each area could be

accurately compared to determine what relationship if any, the chemical composition of the waters might bear to corrosion.

Three water samples were taken in the northern part of the Parker Township pool. Two were from wells in which corrosion is very severe, and one from a well in which corrosion is not troublesome. The water in this pool is produced with the oil from the Westfield lime which is found at an average depth of about 450 feet.

In Lawrence County samples were taken from two wells a few miles north of Bridgeport. One of these wells produces very corrosive water with the oil while the other well, only a short distance away, produces only mildly corrosive water. Both wells are producing from the Bridgeport sand at a depth of about 1,000 feet.

VALUE OF CHEMICAL ANALYSES AS INDICES OF CORROSION

The results of water analyses are given in Tables 1 and 2. No significant differences appear by which the degree of corrosiveness may be determined from the composition of the brines, especially when waters from different sands are compared. For example, sample A, with a high concentration of salts, is moderately corrosive, but sample F, with a low concentration of salts, is very corrosive. In corrosive waters, the sum of the reacting values of $\text{NO}_3 + \text{SO}_4 + \text{Cl}$ is frequently greater than the sum of the reacting values of $\text{NH}_4 + \text{Na} + \text{K}$. This is true of many of the samples, but sample F is an exception. The fact that this water is very corrosive proves that the above relation is no sure indicator of corrosiveness. According to Mills,⁵ corrosive waters are characterized by a high primary salinity generally in excess of 50 per cent, and a secondary salinity generally higher than 20 per cent but sometimes as low as 8 per cent. Sample D, a very corrosive water, is an exception to this classification, having a secondary salinity of 4.94 per cent.

The value of a chemical analysis as an index of the corrosiveness of an oil-field brine seems from this study to be small, except as it indicates the character of the medium in which corrosion occurs. Differences between the analyses of corrosive and noncorrosive waters are so inconsistent that correlation with field observations of the corrosiveness of the waters is impossible.

FIELD STUDIES OF HYDROGEN ION CONCENTRATION AND HYDROGEN SULFIDE CONTENT

The corrosive properties of oil-field waters are thought to be due in a large measure to the hydrogen sulfide and carbon dioxide content as dissolved gases and to the presence or absence of catalysts. Therefore, in addition to the samples taken for chemical analysis, field tests were made on waters from a large number of wells scattered throughout the various pools

⁵ Op. cit., p. 27.

where corrosion is severe to determine the amount of hydrogen sulfide dissolved in the water, and to determine the hydrogen ion concentration which measures the acidity of a liquid. All of these tests were made as soon as the sample was obtained from the well. Only those wells which had been pumping continuously for an hour or more were selected for testing. These precautions were necessary since the hydrogen sulfide content of water lowers rapidly by chemical decomposition and by escape of the gas into the atmosphere when the water is exposed to the air or becomes warmer.

RESULTS OF TESTS

The investigation showed that the hydrogen sulfide content of water indicates its corrosive or noncorrosive qualities only in a very general way. If little or no hydrogen sulfide is present in the water there is probably no corrosion trouble and some waters with relatively high hydrogen sulfide content are only mildly corrosive. Nearly all highly corrosive waters have a high hydrogen sulfide content but there are a few highly corrosive waters which are also relatively low in hydrogen sulfide.

All tests for hydrogen ion concentration indicate that the waters are only very slightly acid or alkaline and in no test was the water sufficiently acid or alkaline so that this property might be considered an important factor in causing corrosive reactions.

SUBSTANCES THAT ACCELERATE CORROSION

The most active and common product that accelerates corrosion is iron sulfide. It is formed by the reaction of the hydrogen sulfide in oil-field waters with the iron or steel equipment in the wells. Iron sulfide is electro-negative with respect to iron, consequently with the electro-positive iron of the equipment it constitutes a minute galvanic battery, and in the presence of water it greatly stimulates corrosion. The following facts seem to indicate the importance of iron sulfide in respect to corrosion.

Many strings of tubing and casing are found to be corroded deepest just above the collars, indicating accelerated corrosion at that point. This is thought to be due largely to the iron sulfide scale which has lodged upon the ledges of the collars, and to the susceptibility to corrosion of strained areas in the casing and collars formed during the threading of the collars and screwing together of the casing.

In many wells the few lower joints of tubing or anchor tubing are found to corrode much faster than the remainder of the tubing string. In some wells this may be due to more complete immersion but in others it is clearly due to the accumulation of iron sulfide around the tubing.

The rate of corrosion in many wells grows progressively more rapid with age, but cleaning out at frequent intervals reduces the corrosion rate. The mud and water removed during the cleaning is usually very dark due

TABLE 1.—*Descriptions of samples*

Analysis No.	Farm name	Well No.	Section	County and township	Producing horizon	Degree of corrosiveness	Remarks
A	Drake Heirs	9	5	Clark County Parker (T. 13 S., R. 14 W.)	"Westfield lime"	Moderate	Steel tubing is replaced once a year and steel lead lines have not been replaced in fifteen years. Water is produced with the oil in relatively large amounts. Steel lead lines last about one year and cast-iron lead lines about three years. Tubing is corroded badly. Water production is high.
B	Drake Heirs	13	5	Clark County Parker (T. 13 S., R. 14 W.)	"Westfield lime"	Very bad	
C	Goble	3	5	Clark County Parker (T. 13 S., R. 14 W.)	"Westfield lime"	Very bad	Bottom joints of three-inch wrought-iron tubing are replaced every four months. Sucker rods are badly corroded. Well is equipped with cast-iron lead line which gives but little trouble. Water production is high.
D	Epperson	8	5	Clark County Parker (T. 13 S., R. 14 W.)	"Westfield lime"	Very bad	Bottom joints of tubing are changed every four months and the whole string once a year. Steel lead lines lasted two years; well is now equipped with cast-iron lead lines. Sucker rods are badly corroded. Water production is high. This well produces considerable water.
E	K. and E. Young	48	17	Clark County Parker (T. 13 S., R. 14 W.)	"Westfield lime"	Moderate	
F	Crump	2	19	Lawrence County Bridgeport (T. 4 N., R. 12 W.)	Bridgeport sand	Very bad	Copperoid tubing is replaced in this well every four months. There is some lead line corrosion upon steel lines; badly corrosive on sucker rods. This well produces a relatively large amount of water.
G	Crump	24	19	Lawrence County Bridgeport (T. 4 N., R. 12 W.)	Bridgeport sand	Very mild	No replacements have been made in this well for several years.
H	L. Gillespie	4	26	Lawrence County Dennison (T. 3 N., R. 12 W.)	Bridgeport sand	Moderate	Water production from this well is moderate.

TABLE 2.—*Detailed analyses*
(Analyses made by State Water Survey)

Sample	NH ₄	Na	K	Ca	Mg	Fe	Al ₂ O ₃	Mn	Totals	SO ₄	Cl	NO ₃	CaCO ₃ *	SiO ₂	H ₂ S*	N. Vol.	Residue	pH	
A	10.3	14,930	398.6	637.5	415.9	0.1	1.0	0.1	402.4	25,040	25,040	1.5	480.0	30.0	31.45	14.0	43,780	7.6	
B	25.9	141,190	2580.0	745.7	457.4	1.4	2.0	0.0	582.6	260,000	260,000	3.0	5.0	1.0	47,917	7.0	
C	9.8	7,582	225.5	476.0	284.3	0.4	0.0	0.0	41.2	13,014	13,014	1.9	476.0	9.0	211.75	37.0	22,980	7.0	
D	10.3	14,720	482.5	486.0	296.1	0.2	3.7	0.0	36.2	24,878	24,878	1.7	620.0	28.0	104.04	26.0	42,920	6.9	
E	11.8	4,209	529.7	152.2	137.6	1.8	6.4	...	290.1	7,000	7,000	4.1	11.5	1.0	13,470	...	
F	5.2	5,887	125.9	78.6	74.7	0.2	0.7	0.2	1521.0	7,896	7,896	1.8	644.0	1.7	88.44	26.0	16,000	7.6	
G	5.2	7,221	162.6	40.0	93.0	0.2	5.7	0.0	132.5	10,696	10,696	1.5	672.0	19.0	38.55	12.0	19,020	8.2	
H	7.7	8,586	356.7	144.4	165.1	10.4	7.1	11,854	11,854	3.0	21.0	33.0	23,240	...	
(Reacting values of the radicals expressed in parts per million)																			
A	0.6	649.5	10.2	31.7	34.2	726.2	8.4	706.1	0.1	9.6	...	0.9	Totals	725.1	...	
B	1.5	603.2	75.8	37.2	37.6	755.3	12.1	733.2	0.0	6.8	752.1	
C	0.6	329.8	6.8	23.8	23.4	384.4	0.9	367.2	0.1	9.5	...	6.2	383.9	
D	0.6	640.3	12.4	24.3	24.3	701.9	0.8	701.6	0.1	12.4	...	3.0	717.9	
E	0.7	183.0	13.5	7.6	11.3	216.1	6.0	197.4	0.1	13.3	216.8	
F	0.3	256.1	3.2	3.9	6.1	269.6	31.6	222.7	0.1	12.9	...	2.6	269.9	
G	0.3	314.1	4.2	2.0	7.6	328.2	2.8	301.6	0.1	13.4	...	1.1	319.0	
H	0.4	373.4	9.12	7.2	13.6	403.7	0.0	334.3	0.5	66.6	401.0	
(Reacting values of the radicals expressed in percentages)																			
A	0.04	44.76	0.71	2.18	2.35	0.58	48.66	0.01	0.64	...	0.06	99.99	100.00	
B	0.1	40.0	5.0	2.5	2.5	0.8	48.6	0.0	0.4	100.00	
C	0.08	42.9	0.88	3.10	3.05	0.12	47.8	0.01	1.24	...	0.81	100.00	100.00	
D	0.04	45.1	0.88	1.71	1.71	0.06	49.4	0.01	0.87	...	0.21	99.99	99.99	
E	0.02	42.3	3.1	1.7	2.6	1.4	45.6	0.0	3.1	100.00	
F	0.05	47.5	0.59	0.72	1.13	5.86	41.3	0.01	2.39	...	0.49	99.99	99.99	
G	0.04	48.5	0.65	0.31	1.18	0.43	46.60	0.01	2.07	...	0.17	99.99	99.99	
H	0.05	46.4	1.13	0.89	1.69	0.0	41.6	0.01	8.28	100.00	
(Reacting properties calculated from reacting value)																			
Primary salinity										Secondary salinity									
A	91.02										7.88								
B	90.2										8.6								
C	87.86										8.08								
D	94.02										4.94								
E	90.8										3.2								
F	94.30																	
G	94.08										1.82								
H	83.12										4.36								
										12.04									

* CaCO₃ calculated as HCO₃ radical.
H₂S calculated as HS radical.

Explanation of tables

Table 1 shows various details concerning the samples whose analyses are given in Table 2.

Table 2 gives the chemical analyses of the samples. The analyses are expressed in three ways: (1) ionic concentration, (2) reacting value in parts per million, and (3) reacting value in per cent.

The ionic analyses show the number of parts of different ions present in a million parts of water by weight. However, inasmuch as different ions possess the ability to react with other substances to different degrees, it is necessary to compute a "reacting value" for each ion. The reaction value is determined by multiplying the concentration of each ion by its "reaction coefficient" which is known for the various ions. Another mode of expressing reacting values is in per cent. The reacting values expressed in parts per million or per cent may be used as a basis for comparing the chemical composition and activity of waters.

The salinity or alkalinity of a water, as measured by the ratios of the strong and weak acid and basic ions, is sometimes used to indicate the character of the reaction the water is able to promote. In the above table, primary, secondary, and salinity express in per cent the balance between the strong acid ions and the alkalies, alkali earths and metals respectively. By the union of weak acid ions with alkalies, alkali earths and metals, primary, secondary and alkalinity respectively are obtained.

to the presence of particles of iron sulfide. This also suggests that the iron sulfide is a factor in accelerated corrosion.

Iron sulfide is also troublesome because it forms as a scale on pipe, tubing, and rods. This scale becomes loose and falls to the bottom of the well where it accumulates in such quantity as to interfere with pumping.

Sulfur is also a substance which stimulates corrosion in certain forms of equipment. It occurs commonly as a product of the decomposition of hydrogen sulfide in water, and is also deposited from hydrogen sulfide bearing gases when they become mixed with the oxygen of the air, or when they are condensed. Sulfur may be found coating both the inside and outside of metallic equipment, such as tubing in wells, and the inside of lead lines and casing. It also collects in rather large amounts in gas traps and gasoline drips. The chief damage done by the sulfur is that it clogs lead and vacuum lines. In the presence of moisture it undoubtedly corrodes metal in the same fashion as does iron sulfide, but the corrosion produced by sulfur is generally secondary in importance to its clogging.

EFFECT OF CORROSION ON VARIOUS MATERIALS

Equipment of the same general character is commonly used throughout the oil fields of the State. Casing is usually steel and is employed in a number of different weights. Some steel casing containing a small amount of copper is also used to a considerable extent. Lead lines are of steel, cast iron, lead-lined steel, and steel containing a small per cent of copper.

Galvanized tubing is used in very small amounts. Sucker rods are of steel, balls and seats usually of steel, bronze, or brass, and working barrels of steel, cast iron, wrought iron or brass. Brass seems to resist oil-field corrosion very well.

In the corrosion of steel the surfaces are commonly pitted. The pits tend to be elongated parallel to the length of the pipe and are usually quite close together. Often they are so elongated that they appear as narrow furrows or flutings. This is more often true of corroded sucker rods than of tubing or casing. Ordinarily pits are bordered by clear uncorroded metal.

Steel equipment containing a small per cent of copper seems to resist corrosion under many conditions, but when hydrogen sulfide is present in the waters in contact with the casing, the copper content does not appear to have any effect upon the rate of corrosion.

Wrought iron corrodes in much the same manner as steel, but the pits are not generally elongated in any one direction nor are there as many pits developed per unit area. The fewer pits probably indicates that the wrought iron is more homogeneous than steel in composition and texture.

Cast-iron lead lines have proved most economical where corrosion is bad. Wrought iron and lead-lined tubing have not retarded corrosion to such an extent that they effect any marked saving over the cheaper steel equipment. Lead-lined tubing has proved unsatisfactory because corrosion occurs at the contact of the lead with the steel. It is almost impossible to obtain a moisture-proof contact here. Galvanized tubing is seldom used because most of that obtainable at the present time contains minute holes through the zinc coating which expose the metal below to corrosion. It is possible that with the development of better methods of applying the coating of zinc, galvanized material will prove quite satisfactory.

CORROSION DATA BY COUNTIES

CRAWFORD COUNTY

Corrosion of oil-field equipment in Crawford County is confined to distinctly localized areas. Those tracts affected by the more intense action are rarely larger than a section in area and often are included within a single lease. Generally the wells in which corrosion is most active produce more water and water which contains more dissolved hydrogen sulfide than the surrounding wells. Corrosion is most troublesome around the margins of the individual pools.

The most important producing sand in the county is the Robinson sand found at an average depth of about 950 feet. In addition there are a few other sands which are productive locally. Any or all of the sands may yield corrosive water.

MAIN CRAWFORD COUNTY POOL

On the Hawkins farm in sec. 1, Oblong Township, operated by the Associated Producers Company, there are several wells between 900 and 1,000 feet deep that produce very corrosive water from the Robinson sand. In general the wells are pumped straight time and the rate of corrosion seems to be related to the amount of water pumped. Some hydrogen sulfide is present in the water. Wrought-iron tubing is used in the wells at the present time, but it is necessary to replace the lower joints of the strings on the average of once every three weeks. Complete replacements of sucker rods and steel lead lines are made every two years. Corrosion of buried lead and vacuum lines here is apparently not due to soil corrosion, for the vacuum lines last much longer than the lead lines.

In sec. 30, Oblong Township, the Reedy and Smith lease of the Mahutska Oil Company, producing from the Robinson sand, is troubled little by corrosion except for a small amount of soil corrosion of buried lead lines. Except in some deeper wells on a nearby lease, extremely corrosive waters are not encountered in this vicinity.

Corrosion is quite serious on the Pearl Dee lease of the Pure Oil Company in sec. 5, Oblong Township, producing from the Robinson sand. Corrosion is most active on that part of the 6¼-inch casing extending below the 8-inch casing which is seated at about 400 feet. The average life of the bottom joints of the 6¼-inch casing is about two years. The places of maximum corrosion are the threaded joints and the areas just above the collars, although the whole string of casing is also quite badly pitted. It would seem that filling the space between the 6-inch casing and the wall of the well with a thick mud might materially reduce this corrosion. The lead lines and sucker rods are seriously corroded, especially where the former are buried in soil which has become impregnated with sulfur and various salts by oil and water refuse from receiving tanks.

In sec. 10, Oblong Township, the J. W. Shire lease of the Mahutska Oil Company produces oil with practically no water from the Robinson sand. Corrosion gives very little trouble here, but occasionally lead lines require replacement.

The C. B. Walker lease of the Ohio Oil Company in sec. 27, Martin Township, produces oil without water from the Robinson sand. There is no corrosion on this lease or in this vicinity, which shows that the salt water and not the oil causes corrosion in the oil fields.

On the G. W. Jones lease of the Ohio Oil Company in sec. 35, Martin Township, the waters are quite corrosive. The wells were all originally drilled through the Robinson sand into water and consequently they must now be pumped straight time at the rate of 20 barrels of fluid per hour. The waters contain dissolved hydrogen sulfide. Corrosion of the 6¼-inch casing is moderately severe and is most active about midway of the well.

Ordinary steel lead lines last about three months for wells most subject to corrosion, but some of the lead-lined pipe has been in use for over two years. Steel tubing lasts about six months; galvanized tubing about twice that long. Sucker rods are commonly replaced when the tubing is changed. Of interest in connection with corrosion in these wells is the fact that anchor tubing is eaten through at a more rapid rate than the tubing above the working barrel, probably because the water acts on it from the outside as well as the inside.

BELLAIR POOL

Corrosion is quite severe on the Susanne Smith lease of the Ohio Oil Company in sec. 11, Licking Township. Production is obtained from two sands, the upper is probably the Robinson sand and the lower is one of the sands of the Chester series. The water from the lower of the two sands is the more corrosive. A comparatively large amount of water is pumped with the oil. It is commonly necessary to replace steel lead lines, tubing, and sucker rods about every year. Many of the lead lines are of cast iron but even these, where corrosion is the most active, must be replaced within a period of two years. Most of the wells that produce from the lower sand in this vicinity are also troubled with corrosion.

PARKER POOL

Probably the most intense and destructive corrosion in the county occurs in the vicinity of the Parker lease in Honey Creek Township in what is commonly called the Parker pool. A great deal of water, high in hydrogen sulfide, is produced with the oil from the Robinson sand. Many of the wells are pumped straight time. Corrosion is particularly bad on sucker rods and the lower joints of tubing and casing. The action of corrosion upon casing seems to be from the outside inward, and below the seat of the 8-inch casing the 6¼-inch pipe shows the effects of corrosion to a greater degree than elsewhere, particularly just above the collars. This corrosion would probably be greatly lessened by the introduction of a thick mud between the 6¼-inch casing and the wall of the well. Cast-iron tubing is used in at least one well, and chain-steel sucker rods in nearly all wells. The lead lines are of cast iron.

BIRDS POOL

In the Birds pool, located in Lawrence and Crawford counties and producing from the Robinson sand, corrosion is not a serious factor. It is confined mostly to working parts such as the balls and seats, and working barrels.

FLAT ROCK POOL

The conditions in the Flat Rock pool in Honey Creek Township are very similar to those in the Parker pool, but the volume of water pumped from most of the wells is less than that pumped from the wells in Parker

pool, consequently the corrosion is slower. Hydrogen sulfide is present in relatively large amounts in the gas and water pumped with the oil. Production is from the Robinson sand.

LAWRENCE COUNTY

The oil fields of Lawrence County have no serious corrosion problems except for an area north of Bridgeport, near Millerville. There are five major producing sands in this area of which the Bridgeport sand is the youngest and most shallow, and carries the corrosive water. In general where the largest volumes of water are pumped the hydrogen sulfide content of the water is highest and corrosion is most active.

CLARK COUNTY

Oil well equipment in Clark County suffers more from corrosion than any other of the counties mentioned. The Siggins pool, northwest of Casey, is the only producing area in the county not seriously affected, and the condition here is probably due to the small amount of water produced with the oil. In general, however, tubing, sucker rods, casing, and lead lines are all destroyed in a relatively short time. Corrosion is worst in the north part of the county. Various kinds of equipment such as copperoid tubing and casing, cast-iron tubing and lead lines, wrought-iron tubing, and lead-lined tubing have been tried in an attempt to increase the length of time between replacements, but only cast iron has been found to resist corrosion for any length of time. It has been used in tubing and lead lines.

WESTFIELD POOL

The Parker Township or Westfield pool probably produces with the oil the most corrosive water in the State. Many of the gas lines, lead lines, and vacuum lines in this pool become choked with a scale high in sulfur, and this necessitates replacing or cleaning the lines at rather frequent intervals.

The gas from this pool has a higher hydrogen sulfide content than any other produced in Illinois, and for that reason very little of it is run through compression or absorption plants to extract gasoline.

The corrosive waters are produced with the oil from the so called "Westfield" lime. Wells producing only from the "Trenton" are not troubled with corrosion. Water from the Niagaran is said to be very corrosive.

CASEY TOWNSHIP, JOHNSON TOWNSHIP, AND MARTINSVILLE POOLS

Corrosive waters are also found in the Casey Township pool, the Johnson Township pool, and the Martinsville pool. In Johnson and Casey townships the production comes mostly from one sand, the Casey sand, which yields considerable water with some dissolved hydrogen sulfide.

In the Martinsville pool production is principally from two sands, the Carper and the Niagaran. Nearly all of the wells produce from the two sands at the same time. For two years or more nearly all of the wells in this pool produced only from the Carper sand, and no trouble from corrosion was encountered in any of the wells until they had been deepened to the Niagaran. Soon after this it was noticed that tubing and rods required replacement more often than before. Unfortunately, most of the water, and oil too, are produced from this formation, so that plugging it off would both prevent rapid corrosion and take away the best part of the oil production.

